Luke
ENERGY

2004 ANNUAL REPORT

Annual Meeting

Luke Energy invites its shareholders and other interested parties to attend the Company's Annual Meeting on Thursday, May 19, 2005 at 3:00 p.m. in the Viking Room of the Calgary Petroleum Club, 319 - 5th Avenue S.W., Calgary, Alberta.

Contents

Corporate Profile

Luke Energy Ltd. is an emerging oil and gas company based in Calgary and operating in western Canada. Luke Energy's growth strategy is to grow through a combination of internally generated drilling opportunities and strategic acquisitions.

During 2004 Luke Energy increased its reserve base to 324,000 barrels of oil and 20.9 billion cubic feet of gas for a total of 3.8 million barrels of oil equivalent. Production volumes reached 1,100 boepd by year-end and were weighted 95% to gas.

At December 31, 2004 Luke Energy had approximately 37 million shares outstanding, $17.2 million in working capital and no debt. The Company's shares are listed on the Toronto Stock Exchange under the symbol "LKE".

Abbreviations

bbls	barrels
Mbbl	thousand barrels
MMbbl	million barrels
bbl/d	barrels per day
bopd	barrels of oil per day
Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcfpd	thousand cubic feet per day
MMcfpd	million cubic feet per day
NGL	natural gas liquids
boe	barrels of oil equivalent (6 Mcf=1 boe)
boepd	barrels of oil equivalent per day

Stock Market performance ($ per share)

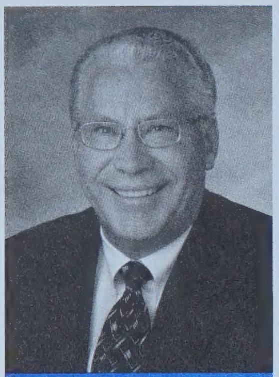
Volume Traded (000's)

Highlights

	Year ended December 31, 2004	Period ended December 31, 2003
Operating		
Producing days	366	309
Production		
Oil – bopd	76	88
Gas – Mcfpd	4,103	380
Total – boepd (6 Mcf = 1 bbl)	760	152
Product Prices ($Cdn)		
Oil – $/bbl	$ 47.77	$ 35.08
Gas – $/Mcf	$ 6.25	$ 6.47
Drilling Activity		
Oil wells	–	–
Gas wells	11.0	1.0
Dry	4.0	–
Total wells	15.0	1.0
Net Wells	13.5	1.0
Reserves		
Oil – Mbbl	324	300
Gas – MMcf	20,855	2,138
Total – Mboe	3,800	658
Undeveloped Lands		
Net acres	33,319	16,600
Financial ($Cdn except per share numbers)		
Gross production revenue	$ 10,705,520	$ 1,715,620
Cash flow [1]	$ 5,221,510	$ 1,374,948
Per share – basic and diluted	$ 0.15	$ 0.05
Earnings	$ 1,100,442	$ 369,834
Per share – basic and diluted	$ 0.03	$ 0.01
Weighted average shares outstanding	35,204,971	29,759,428
Shares outstanding	36,997,823	34,828,949
Capital expenditures	$ 28,818,064	$ 4,834,865
Working capital	$ 17,208,655	$ 35,026,238
Shareholders' equity	$ 50,500,841	$ 42,814,715

1 Cash flow means earnings before future taxes, depletion, depreciation, accretion, and stock-based compensation.

Report to Shareholders



Harold V. Pedersen
President & CEO

Luke Energy Ltd. is pleased to report that during its second year of operations the Company changed from being a "cash rich start-up" to a fully operational oil and gas company. In 2004 Luke Energy completed a highly successful drilling program and firmly established Marten Creek in northern Alberta as its first core area. The combination of successful drilling and strong commodity prices resulted in attractive financial results.

2004 Highlights

The Company drilled 15 wells resulting in 11 successful gas wells, with nine at Marten Creek in northern Alberta and two at Bernadet in northeastern British Columbia.

- Year-end production rose to 1,100 boepd comprising 6.2 MMcfpd and 67 bopd.
- Capital expenditures for the year were $28.8 million, the main components of which are: $8.5 million in drilling and equipment; $4.6 million in pipelines and facilities; $2.2 million in pipeline and casing inventory; $7.4 million in land; $3.2 million in seismic; and $2.7 million in acquisitions.
- Proved and probable reserves grew to 3.8 million boe by year-end and were comprised of 324,000 bbls of oil and 20.9 bcf of gas.
- Finding costs of $10.60 per boe were recorded for proved reserves and $7.97 per boe for proved plus probable reserves.
- The Company achieved strong financial results. Cash flow for the year was $5.2 million ($0.15 per share) and net earnings were $1.1 million ($0.03 per share). At December 31, 2004, the Company had working capital of $17.2 million and no debt.
- Two financings were completed in the third and fourth quarters totalling $5.8 million. Both were private placements of common shares on a "tax flow-through basis" – one in September raised $3.4 million at $2.65 per share; and the other in December raised $2.4 million at $3.10 per share.

Outlook

The Company's near-term growth strategy is to focus on generating new drilling prospects while continuing to look for strategic acquisitions. We have found it difficult to be competitive in the acquisition market because of the high prices being paid by the royalty trusts in Canada.

Luke Energy's prospect generation has already resulted in the establishment of the Company's first core area at Marten Creek where the target is shallow, long-life multi-zone gas. A ten well program in the first quarter of 2004 resulted in eight successful wells. The result of the program was to generate strong value for the Company at an attractive finding cost. A second multi-well program was initiated prior to year-end which resulted in drilling 24 wells with 18 successes. The initial test results are encouraging and pipelining is in progress to tie the wells in for production.

We are optimistic that our geological and geophysical team have identified two potential new gas areas in Alberta, one at Seal, which is northwest of Marten Creek and the other is in western Alberta. An acreage position has been established at Seal and other land acquisitions will be made in the second quarter of 2005. The play types are seismically predictable, our technical team has experience in the areas and if successful, there is sufficient open land that can be acquired to develop new core areas.

Commodity prices continue to remain strong. Geopolitical uncertainty in the Middle East and strong demand world-wide are expected to keep oil prices high. The outlook on gas is also favorable, although we may see some softening in the first half of the year because of high storage levels and the late start on winter demand.

We are grateful to our staff for their dedication and initiative over the past year in establishing our new production base. In addition, we appreciate the enthusiastic support and counsel from our Board of Directors.

We would also like to thank our shareholders for their ongoing support and trust in our stewardship.

Respectfully Submitted
On Behalf of the Board of Directors,

Harold V. Pedersen
President & CEO
March 8, 2005

Operations Overview

Luke Energy's growth strategy is to grow through a combination of internally generated medium risk drilling opportunities together with strategic acquisitions having development potential. The Company's operating strategy is to develop core-operating areas in western Canada and to maintain operatorship and high interests in its projects. A key principle is to add value by maintaining a low finding and operating cost structure.

Prospect Review

Rob Wollmann
Vice-President
Exploration

Marten Creek, Northern Alberta

Marten Creek is located approximately 300 miles north of Calgary. It is a relatively shallow (1,925 feet), multi-zone gas prospect in the Cretaceous with long-life reserves. This is an in-house project initiated by Luke's geological team in mid 2003. Luke's land position has almost tripled over the past year to an average 85% interest in some 38,000 acres. The Company also holds an additional 8,320 acres under option.

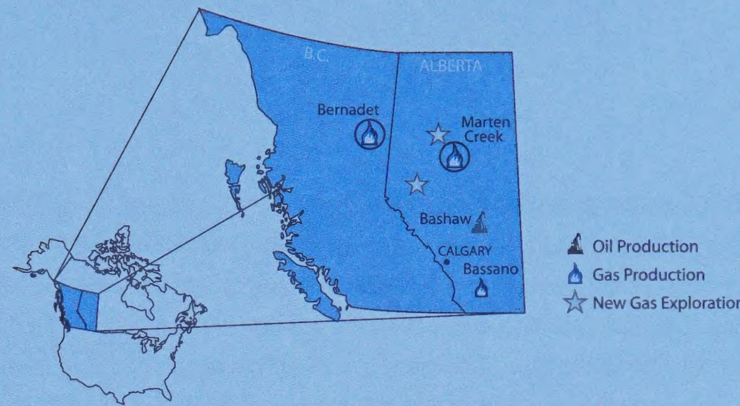
During the first quarter of 2004 the Company drilled ten wells with eight successes. Initial gas production from seven wells commenced in March at 4.5 MMcfpd and was gradually increased during the year to over 6 MMcfpd reflecting the higher deliverability capability from the wells and the expansion of third party processing facilities.

The reserve potential for the project is attractive averaging 1 to 2 Bcf of gas per well. The costs to drill, complete and tie-in a well are in the range of $425,000.

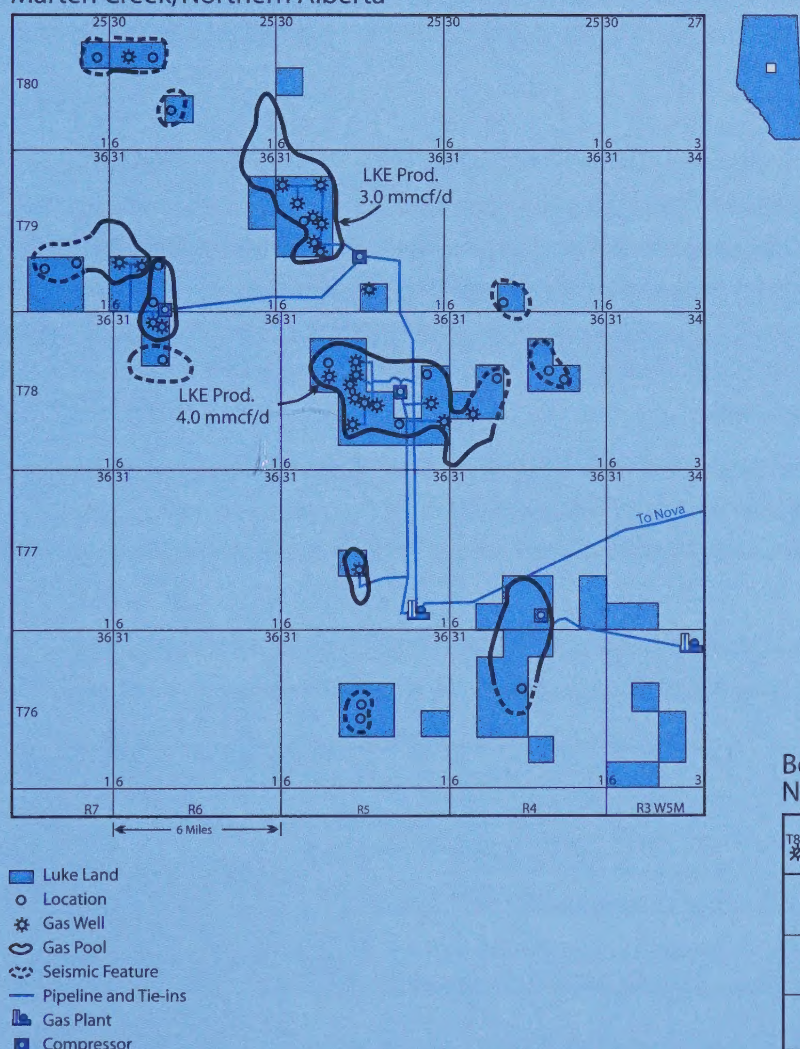
The Company has accumulated a seismic base of 770 miles of 2D seismic data on which over 35 potential drilling locations have been identified on existing lands.

Based on that information, a second multi-well program was commenced in late December with 24 wells drilled by the end of February resulting in 18 cased wells. Well testing is underway and thus far at least half of the wells are each capable of producing over 1 MMcfpd. Pipelining is in progress and two additional field compressors are being installed. This is a winter work area and all work must be completed by March 15th which is generally the start of spring breakup.

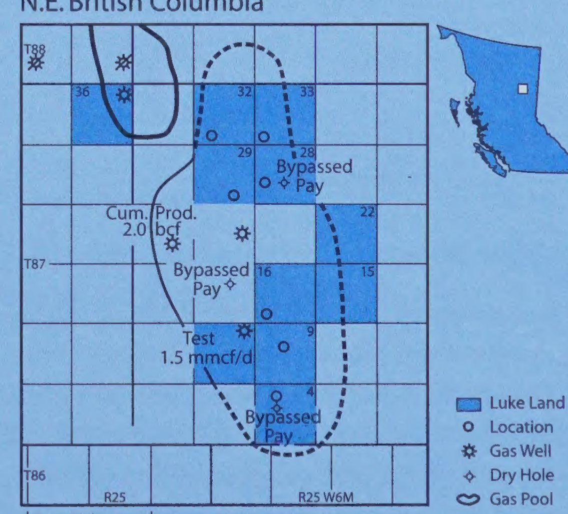
Initial results from the winter program are encouraging and the Company is on target to double its current production from 6 MMcfpd to 12 MMcfpd (2,000 boepd) in the second quarter. The Company will continue to expand its position in the area and another multi-well drilling program is planned for next winter.



Marten Creek, Northern Alberta



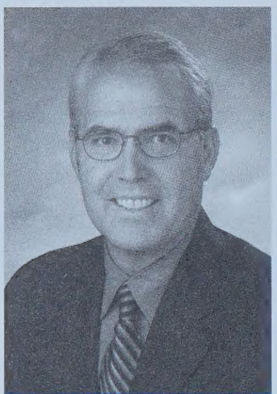
Bernadet,
N.E. British Columbia



Bernadet, Northeastern British Columbia

Bernadet is located about 65 miles west of the Alberta border in northeastern British Columbia. This is a new exploration project developed by Luke on which we drilled a gas discovery in December which tested at 1.5 MMcfpd on completion. It appears to be in a gas charged fairway and we potentially have four to eight additional locations. Luke operates this project with a 50% interest in 7,260 acres on the play. Our target here is Bluesky gas at a depth of 3,500 feet with reserve potential of 1 to 3 Bcf per well. The cost to drill a well is about $650,000.

A two mile pipeline is being constructed to the main line in order to place the discovery well on production. An offset well is also planned prior to spring break-up which would also be pipeline connected. Additional drilling is planned for the summer and fall.



Peter W. Abercombie
Vice-President
Land

Land

During the past year Luke Energy was an active participant at Crown land sales. The Company focused on expanding its acreage position in its core area of Marten Creek, Alberta and on acquiring prospective acreage in new exploration areas. As a result Luke Energy's undeveloped land inventory has doubled to 33,319 net acres (as compared to 16,600 net acres in 2003). The Company now holds an average 81% interest in 41,168 gross undeveloped acres.

Luke Energy's undeveloped lands were valued at $7.87 million by the independent land consulting firm of Seaton-Jordan & Associates Ltd. in their year-end report. This is up from the $2.92 million attributed to Luke Energy's lands in the Seaton-Jordan report of a year ago.

Luke Energy will continue to build its undeveloped land inventory in 2005 as the Company's exploration team develops other new exploration areas.

	2004		2003	
Acres	**Gross**	**Net**	Gross	Net
Alberta	**33,920**	**27,721**	20,500	16,600
British Columbia	**7,248**	**5,598**	–	–
Total	**41,168**	**33,319**	20,500	16,600
Value of net acres ($millions)		**$7.87**		$2.92
Average working interest		**81%**		81%

Production

Luke's annual production rose 400% to 760 boepd (90% gas) from 152 boepd (58% oil) a year ago. The production increase was mainly due to drilling success at Marten Creek which commenced production in March 2004 at 4.5 MMcfpd. Marten Creek well performance was above expectations and production from the wells had increased to over 6 MMcfpd at year-end. Luke's exit production rose 680% to 1,100 boepd (93% gas) from 141 boepd. Luke operates 100% of its gas production and 85% of its oil production. Luke expects to see significant production growth from its 2005 drilling program at Marten Creek. In addition, Luke will be developing its Bernadet gas project in British Columbia where production is expected to commence in the second quarter of 2005.

During the year, the Company spent 70% of its $28.8 million capital program or $20.2 million at Marten Creek. Approximately 29% of the Marten Creek program was spent on drilling, 32% on facilities and flowlines, 27% on land and 12% on seismic and acquisitions.

Average Daily Company Interest Production

	2004	2003
Gas (Mcfpd)	4,103	380
Oil & NGL (bbl/d)	76	88
Combined (boepd)	760	152

Drilling

Luke Energy drilled 15 wells during 2004 with an average interest of 90%. The Company drilled 11 successful gas wells with nine at Marten Creek and two at Bernadet. The Company drilled four unsuccessful wells, one in Marten Creek, one in Bassano and two on exploratory projects in northeast B.C.

In addition two successful gas wells were drilled on farmouts in western Alberta at no cost to Luke Energy. The Company has a 9.75% royalty interest until payout in each well which reverts to a 26% interest at payout.

Wells Drilled

	2004		2003	
Years Ended December 31	Gross	Net	Gross	Net
Gas	11	10	1	1.0
Oil	–	–	–	–
Dry	4	3.5	–	–
Total	15	13.5	1	1.0
Exploratory	11	10.5	1	1
Development	4	3.0	–	–
Total	15	13.5	1	1
Average Working Interest		90%		100%

Kevin Lee
Vice-President
Engineering

Reserves

Luke's reserves were evaluated by the independent engineering firm of Gilbert Laustsen Jung Associates Ltd. (GLJ), in accordance with the definitions set out under National Instrument 51-101 (NI 51-101) Standards of Disclosure.

Proved gas reserves were up 15 fold in 2004 to 14.9 billion cubic feet from 1.0 billion cubic feet a year earlier. Proved plus probable gas reserves increased 10 fold to 20.9 billion cubic feet from 2.1 billion cubic feet.

Proved oil and liquids reserves increased slightly to 278,000 barrels from 267,000 barrels in 2003. Proved plus probable oil and liquid reserves are 324,000 barrels versus 300,000 barrels last year.

On a proved boe reserve basis, the Company replaced 935% of 2004 production. On a proved plus probable basis, Luke replaced 1,231% of production.

Oil and Gas Reserves

December 31, 2004	Light Oil & NGL Gross Mbbls	Light Oil & NGL Net Mbbls	Gas Gross MMcf	Gas Net MMcf	BOE[1] Gross Mboe	BOE[1] Net Mboe
Proved Reserves						
Producing	261	197	8,922	7,091	1,748	1,379
Non-Producing	14	11	5,202	4,089	881	693
Undeveloped	3	2	743	604	127	103
Total Proved	278	210	14,867	11,784	2,756	2,175
Probable Reserves	46	35	5,988	4,628	1,044	806
Total Proved + Probable	324	245	20,855	16,412	3,800	2,981

1 Gas is converted to oil at 6 Mcf to 1 bbl.
Company interest reserves are working interest and GORR reserves before the deduction of any royalty.
Net reserves are the working interest reserves with royalty deductions.

Net Present Worth of Reserves

December 31, 2004	Present Worth ($000's)[1] Discounted at the Rate of 0%	5%	10%
Proved Reserves			
Producing	$36,378	$30,333	$26,153
Non-Producing	17,515	13,880	11,340
Undeveloped	2,584	2,028	1,681
Total Proved	56,477	46,241	39,174
Probable Reserves	21,042	15,196	11,680
Total Proved + Probable	$77,519	$61,437	$50,854

1 Values shown are calculated on a before tax basis.

Gilbert Laustsen Jung January 1, 2005 Price Forecast Year	Oil WTI Ref US $/bbl	Natural Gas AECO C Spot Cdn $/MMbtu
2005	42.00	6.60
2006	40.00	6.35
2007	38.00	6.15
2008	36.00	6.00
2009	34.00	6.00
2010-12	33.00	6.00
2013-15	+1.5%/yr.	+1.5%/yr.
2016+	+2.0%/yr.	+2.0%/yr.

Crude oil price is WTI at Cushing, Oklahoma. Natural gas is the AECO spot price.

Reconciliation of Reserves

The following table provides a summary of the changes in Luke Energy's reserves during the past year.

	Oil & NGL (Mbbl)			Natural Gas (MMcf)			BOE (Mboe)		
Reserves	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
As at December 31, 2003	267	33	300	1,011	1,127	2,138	436	222	658
Drilling	14	5	19	15,126	4,253	19,379	2,535	714	3,249
Revisions	(96)	(5)	(101)	(261)	502	241	(140)	79	(61)
Total Additions	(82)	0	(82)	14,865	4,755	19,620	2,396	793	3,188
Acquisitions	121	13	134	492	106	598	203	29	232
Production	(28)		(28)	(1,501)		(1,501)	(278)	0	(278)
As at December 31, 2004	278	46	324	14,867	5,988	20,855	2,756	1,044	3,800

The majority of the reserve additions (86%) came from the Company's successful gas drilling program at Marten Creek. Early success at Luke's emerging play at Bernadet also contributed incremental reserves. Strategic acquisitions at Bashaw and Marten Creek added 6% to total reserves. Revisions were minor, primarily as a result of higher water cuts at Bassano and Bashaw.

Reserve Life Index

Luke Energy's reserve life index comparing total reserves and production for the 2004 and 2003 fiscal year-end is as follows:

Years	**2004**	2003
Proved Reserves	**6.9**	8.9
Proved + Probable Reserves	**9.5**	13.5

Proved and Proved + Probable Reserves are divided by the annualized December 2004 production of 1,095 boepd to derive the Reserve Life Index.

Net Asset Value

Luke Energy's net asset value has steadily increased since start-up. The majority of the Company's year-end 2003 net asset value was comprised of cash. Net asset value at the end of 2004 grew to $2.11 per share at a 10% present worth discount versus $1.28 per share a year earlier as a result of value added through drilling.

		2004 Present Worth Discount (before taxes)		2003 Present Worth Discount (before taxes)	
Reserve Value ($000)		**0%**	**10%**	0%	10%
Proved + probable		**77,519**	**50,854**	10,576	6,588
Add:	Land value	**7,874**	**7,874**	2,915	2,915
	Working capital	**17,209**	**17,209**	35,026	35,026
	Pipe inventory	**2,210**	**2,210**	–	–
Net asset value		**104,812**	**78,147**	48,517	44,529
Net asset value per share		**$2.83**	**$2.11**	$1.39	$1.28

Finding and Development Costs

Luke Energy's finding and development costs ("F&D") are attractive and reflect the efficiency and value added by the Company's capital spending.

		2004
Exploration & Development Costs ($million)	$	23.9
Future Development Costs ($million)	$	1.5
Proved Reserves Additions (Mboe)		2,396
F&D Cost ($/boe)	$	10.60
Proved + Probable Reserves Additions (Mboe)		3,188
F&D Cost ($/boe)	$	7.97

Finding and development costs were calculated using the method outlined in NI 51-101 which provides that exploration and development costs plus future development costs are divided by the Company's reserves additions.

Acquisition costs of $2.7 million were excluded from the calculation as well as pipe inventory of $2.2 million acquired in December for the 2005 Marten Creek drilling program.

Marketing

Luke Energy received an average of $47.77 Cdn per barrel for its oil in 2004. Luke's production averaged 76 barrels per day of light gravity oil from Bassano (30 degrees API) and Bashaw (37 degrees API). The Company markets its crude oil under 30 day evergreen contracts with Nexen Marketing.

The Company's natural gas price averaged $6.25 Cdn per Mcf in 2004. The Company's average annual natural gas production was 4.1 MMcf per day in 2004. Luke sold more than 95% of its natural gas production to Nexen Marketing on the daily spot market during the year.

Environmental and Safety Programs

Luke Energy is committed to protecting the health and safety of its employees and the public, as well as preserving the quality of the environment. The Company has a formal Emergency Response Plan and Safety Policy Guidelines in place to ensure the safe operations of its oil and gas properties.

The Company commissioned independent consultants to conduct detailed environmental audits on all existing and newly operated property. All areas exceeded required standards and compliance guidelines.

Area specific Emergency Response Plans have been prepared for all of Luke's established operating areas. In addition, we have conducted simulation drills both at the field level and in Calgary, to ensure preparedness in the event of an emergency. Luke's environmental and safety procedures are monitored and updated on an ongoing basis.

Management's Discussion and Analysis

Carrie McLauchlin
Vice-President
Finance & CFO

The following discussion and analysis of financial results should be read in conjunction with the audited financial statements of the Company for the year ended December 31, 2004, together with the notes related thereto. The discussion contains forward-looking statements that involve risks and uncertainties. Such information, although considered reasonable by Luke Energy management at the time of preparation, may prove to be inaccurate and actual results may differ materially from those anticipated in the statements made.

The Company evaluates its performance based on earnings and cash flow. Cash flow is a non-GAAP (Generally Accepted Accounting Principle) term that represents earnings before depletion, depreciation and accretion, future income taxes and stock-based compensation. Cash flow per share is calculated using the same weighted average number of shares outstanding as earnings per share. These non-GAAP measures are not standardized and therefore may not be comparable to similar measures by other entities. It is a key measure as it demonstrates the Company's ability to generate cash necessary to fund future growth through capital investment. Cash provided by operating activities is the GAAP term. The difference between the GAAP and the non-GAAP term is the change in non-cash working capital items.

In this discussion and analysis, certain natural gas volumes have been converted to barrels of oil equivalent (boe) on the basis of six thousand cubic feet (6 Mcf) to one barrel (1 bbl). Boe may be misleading, particularly if used in isolation. A boe conversion ratio 6 Mcf=1 bbl is based on an energy equivalency conversion method, primarily applicable at the burner tip and does not represent equivalency at the well head.

The date of this management discussion and analysis is March 8, 2005.

Oil and Gas Operation Summary

	Year Ended December 31, 2004	Period Ended December 31, 2003
Producing days	**366**	309
Production:		
Oil – bopd	**76**	88
Gas – Mcfpd	**4,103**	380
Total – boepd	**760**	152

	($000's)	**($/boe)**	($000's)	($/boe)
Oil and gas revenues	**$ 10,706**	**$ 38.50**	$ 1,716	$ 36.63
Royalties, net of ARTC	**(2,009)**	**(7.22)**	(435)	(9.28)
Operating expenses	**(1,991)**	**(7.16)**	(263)	(5.61)
	$ 6,706	**$ 24.12**	$ 1,018	$ 21.74

Production and Revenue

Luke Energy's gas production increased significantly to 4.1 MMcfpd in 2004 from 380 Mcfpd in 2003 due to the drilling success at Marten Creek in the first quarter of 2004. As a result of increased production, oil and gas revenues increased over sixfold to $10.7 million from $1.7 million last year. In addition, the Company's oil and gas revenues benefited by the 5% higher commodity prices on a barrel equivalent basis. The Company's average oil price was $47.77 per bbl (2003 – $35.08 per bbl) while gas averaged $6.25 per Mcf (2003 – $6.47 per Mcf).

Production volumes in the fourth quarter of 2004 were 1,047 boepd versus 137 boepd last year as a result of the increased production from Marten Creek. Fourth quarter oil and gas revenues totaled $3.6 million as compared to $0.4 million for the comparable quarter in 2003. Oil and gas prices in the fourth quarter of 2004 were also higher than last year. The Company's oil price averaged $51.64 per bbl (Q4 2003 – $33.88 per bbl) and the gas price averaged $6.11 per Mcf (Q4 2003 – $5.57 per Mcf).

Royalties

($000's)		2004		2003
Crown royalties	$	2,091	$	–
Other royalties		404		435
Alberta Royalty Tax Credit		(486)		–
Net royalties	$	2,009	$	435
Average royalty rate as a percentage of oil and gas revenues		19%		25%

Net royalties increased to $2 million from $435,000 last year due to the higher production volumes. The lower average royalty rate of 19% compared to 25% last year is attributable to the gas production at Marten Creek which is eligible for the Alberta Royalty Tax Credit and a reduced crown rate based on production levels.

Fourth quarter net royalties were $727,000 as compared to $110,000 last year. The increase is due to the higher production volumes quarter over quarter.

Operating Expenses

Operating expenses were up from $263,000 ($5.61 per boe) last year to $2 million ($7.16 per boe) in 2004. The main increase in operating costs was at Marten Creek which averaged $6.80 per boe for the year. These costs are primarily from third party transportation and processing fees. The remainder of the increase is due to the increased per unit costs at Bashaw and Bassano where production has declined, however fixed costs remain unchanged.

The fourth quarter operating expenses for 2004 were $618,000 as compared to $79,000 last year. The increase is due to the Company's growth in production.

General and Administrative Expenses

General and administrative expenses for the year were $2.0 million as compared to $1.1 million last year. As a result of increased production, general and administrative expenses were down to $7.06 per boe for the year as compared to $24.06 last year. The Company has the staffing in place to manage a much larger production base with minimal incremental costs.

Depletion, Depreciation and Asset Retirement Obligation

The annual provision for depletion, depreciation, and accretion increased to $2.4 million from $489,000 in 2003. The average cost in 2004 was 24% lower at $8.48 per boe as compared to $10.54 per boe last year. The fourth quarter provision for depletion, depreciation and accretion was $925,140 ($9.61 per boe) as compared to $161,275 ($12.78 per boe) last year. The per barrel of oil equivalent decreases year over year result from the successful drilling program at Marten Creek.

The following table summarizes the expense:

($000's)		2004		2003
Depletion of petroleum and natural gas properties	$	**2,261**	$	463
Depreciation of office furniture and equipment		**84**		26
Accretion of asset retirement obligation		**13**		4
Total depletion, depreciation, and accretion	$	**2,358**	$	493

Included in the depletion of petroleum and natural gas properties is $44,175 (2003 – $8,416) representing the depletion on the capitalized retirement obligation of $491,460 (2003 – $106,460).

Taxes

The current tax expense for the year ended December 31, 2004 is only $5,000 versus $96,800 last year. This provision relates exclusively to the Federal Large Corporations Tax. Last year the Company did not qualify for the capital base exemption because it was taken by KeyWest Energy Corporation, the former parent company.

The provision for future taxes of $1.1 million is 49% of pre-tax earnings as compared to $290,000 last year or 38% of pre-tax earnings. The lower rate for last year is due to the gain on sale of the Government of Canada bonds resulting in a capital gain which is only 50% taxable.

At the end of 2004, the Company had approximately $28 million of accumulated tax pools that are available for deduction against future earnings.

		$000's	Annual Deduction Rate
	$	3,656	100%
Canadian development expense		3,028	30%
Canadian oil & gas property expense		13,436	10%
Undepreciated capital cost		6,326	20%-30%
Share issue costs		1,629	20%
Non-capital losses		148	100%
	$	28,223	

Cash Flow and Earnings

Luke Energy's cash flow increased 280% to $5.2 million ($0.15 per share) in 2004 from $1.4 million ($0.05 per share) a year earlier. The higher cash flow reflects the production growth generated by the successful drilling program at Marten Creek. Last year's cash flow also included a one-time $505,000 gain on the sale of marketable securities.

Fourth quarter cash flow was also up significantly to $1.9 million from $247,195 last year as a result of higher gas production.

The Company's fourth quarter and annual earnings were also up significantly as compared to last year as a result of the higher gas production.

Capital Expenditures

($000's)		2004		2003
Land	$	7,408	$	2,077
Seismic		3,192		1,064
Drilling and equipping		8,478		953
Facilities and flowlines		4,608		565
Pipe and casing inventory		2,210		–
Property acquisitions		2,707		–
Corporate		215		176
	$	28,818	$	4,835

The increase in capital expenditures to $28.8 million this year from $4.8 million last year reflects increased activity levels. The Company drilled 15 gross (13.5 net) wells in 2004 as compared to one well last year. Land and seismic costs were higher than last year due to the expansion of the Marten Creek area as well as generating new prospect areas. In addition, the Company completed two minor property acquisitions during the year; one at Bashaw where the Company bought out its 50% partner in two wells and the second was in the southeastern part of Marten Creek where a small interest was acquired in several wells plus an interest in a pipeline and compressor which will be used to expand the Company's program.

The Company also incurred $2.2 million of costs in December for purchasing pipe and casing for the 2005 Marten Creek drilling program. It was necessary to secure these materials in advance as supply shortages were expected given the record drilling activity.

2005 Outlook

The Company projects 2005 cash flow of approximately $13 million ($0.35 per share) and earnings of $3.3 million ($0.09 per share). The increased cash flow and earnings estimates are based on a 40 well drilling program for the year. Approximately 25 of the wells will be drilled at Marten Creek. Production is forecasted to average 1,950 boe per day and will be made based on expected success from the Marten Creek drilling program. The capital expenditure budget for the year is $46 million and over 60% is allocated to Marten Creek where the majority of the program will be carried out in the first quarter because it is a winter access area only.

Cash flow will be dependant upon a number of variables, including forecast prices and production. The following outlines the critical assumptions in the forecast:

Production		
Natural Gas (Mcfpd)		11,410
Oil and NGL (bbl/d)		48
Oil equivalent (boepd)		1,950
Capital expenditures ($000's)	$	46,000
Wells drilled		40
Pricing		
Natural gas (AECO $CDN/Mcf)	$	6.50
Oil (WTI $US/bbl)	$	35.00

The Company's 2005 estimated cash flow and earnings sensitivity to a $0.25 change in natural gas prices is as follows:

		$000's		Per Share
Cash flow	$	830	$	0.02
Earnings	$	475	$	0.01

Liquidity and Capital Resources

The Company is well capitalized for growth with working capital of $17.2 million and an $16 million credit facility. The 2005 capital expenditure program of $46 million will be funded by working capital, cash flow and credit facility borrowings.

During 2004 the Company issued a total of 2.1 million common shares on a tax flow-through basis for gross proceeds of $5.7 million. Management and directors subscribed for approximately 20% of the issued stock.

At December 31, 2004 the Company had 36,997,823 common shares outstanding. In addition, the Company had 3,214,333 stock options outstanding at an average exercise price of $1.69 per share. Options vest equally over three years and have a five year term. At year-end 846,667 options were exercisable at an average exercise price of $1.55.

Contractual Obligations

The Company is committed to spend $5.5 million in 2005 on qualifying Canadian exploration expenses pursuant to the flow-through shares that were issued during the year. In addition, the Company's obligation for its office lease is approximately $220,000 a year for the next five years.

Selected Quarterly Information

	2004				2003			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Production								
Oil – bopd	**61**	**76**	**101**	**66**	88	88	93	76
Gas – Mcfpd	**5,913**	**5,004**	**4,600**	**865**	296	395	401	508
Total boepd	**1,047**	**910**	**868**	**210**	137	154	160	161
Financial								
($000's except per share amounts)								
Gross production revenue	**$3,618**	**$3,073**	**$3,291**	**$724**	$426	$487	$537	$266
Cash flow	**1,893**	**1,484**	**1,346**	**499**	248	772	287	68
Per share – basic and diluted [1]	**0.05**	**0.04**	**0.04**	**0.01**	0.01	0.02	0.01	0.01
Earnings	**479**	**282**	**256**	**83**	(80)	397	59	(6)
Per share – basic and diluted [1]	**0.01**	**0.01**	**0.01**	**0.00**	(0.00)	0.01	0.00	(0.00)
Total assets	**$59,448**	**$50,645**	**$46,404**	**$49,309**	$45,228	$43,607	$40,612	$41,669

1 The sum of the quarterly per share amounts may not necessarily equal the annual per share amounts due to the different weightings of shares issued during the year.

Quarterly Review Comments:

- Earnings (loss) and per share amounts have been restated due to the retroactive change in accounting policy for stock-based compensation. This restatement resulted in a loss for the first quarter and fourth quarter of 2003. See note 3 to the financial statements.
- Cash flow and earnings for the third quarter of 2003 were positively impacted by a $505,000 gain on sale of Government of Canada bonds.
- Financial results greatly improved starting in the second quarter of 2004 due to the onset of production from first quarter 2004 drilling program at Marten Creek.

Critical Accounting Estimates

Significant accounting policies are contained in note 2 to the financial statements. The following discusses the accounting estimates that are critical in determining the reported financial results:

Full Cost Accounting

The Company follows the full cost method of accounting as prescribed by Accounting Guideline # 16 issued by the CICA. All costs for exploration and development of reserves are capitalized in a single cost centre. The costs are depleted on the unit of-production method based on estimated proved reserves. The capitalized costs may not exceed a ceiling amount. If the net capitalized costs are determined to be in excess of the calculated ceiling, which is normally a reserve-based estimate, the excess must be expensed. Proceeds on disposal of properties are deducted from such costs without recognition of a gain or loss except where such disposal is a significant portion of the reserves.

An alternative method of accounting for oil and natural gas operations is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs are charged against earnings as incurred rather than being capitalized. Also, under this method the cost centre is defined to be a property rather than a country cost centre.

Reserves

The Company engages independent petroleum engineering consultants to evaluate its reserves.

Reserve determinations involve forecasts based on property performance, future prices, projected future production and the timing of future capital expenditures, all of which are subject to uncertainties and interpretations. Reserve estimates have a significant impact on reported financial results as they are the basis for the calculation of depreciation and depletion and many non-GAAP key performance indicators.

Revisions can change reported depletion and depreciation and earnings; downward revisions could result in a ceiling test write-down.

Asset Retirement Obligation

The Company provides for the estimated abandonment costs of properties using a fair value method. This future estimate is based on estimated costs and technology following current legislation and industry practice. The reported liability is a discounted amount. The amount of the liability is affected by factors such as the number of wells, the timing of the expected expenditures and the discount factor. These estimates will change and the revisions could impact the depletion and depreciation rates.

Financial Reporting and Regulatory Changes

New and amended standards described below were implemented by the Company in 2004 with the following impact:

Stock-based Compensation

On January 1, 2004 the Company adopted the amended CICA standard for "Stock based compensation and other stock based payments." The amendment requires that companies measure all stock based payments using the fair value method of accounting and recognize the compensation expense in their financial statements. The fair value was estimated using the Black-Scholes option pricing model. The Company applied the change in policy retroactively with restatement of prior period financial statements. The change resulted in a reduction in earnings of $698,113 ($0.02 per share) for the year ended December 31, 2004 and $214,092 ($0.01 per share) for the period ended December 31, 2003.

Certain new and amended standards are expected to impact the Company in 2005 as follows:

Reporting on Internal Control over Financial Reporting

In February of 2005, the Ontario Securities Commission released a draft National Instrument 51-111 "Reporting on Internal Control over Financial Reporting". The instrument proposes a requirement for reporting issuers to complete an internal control evaluation and have their external auditors give an opinion on the Company's internal control in conjunction with the year-end audit. This proposed legislation will be substantially consistent with the United States Securities Commission ("SEC") rules as outlined in section 404 of the Sarbanes-Oxley Act. The proposed legislation would require Luke Energy, based on

current market capitalization, to complete their internal control evaluation by December 31, 2008. However, Luke Energy is a Foreign Private Issuer and files a Form 20-F with the SEC. Accordingly, under the Sarbanes-Oxley Act in the United States, the CEO and CFO of Luke Energy have been filing "Bare" certificates since the first quarter of 2003 with their financial statements. For the Company's year end filing for 2006, the CEO and CFO will be required to file "Full" certificates. This will require the Company to complete an internal control evaluation before December 31, 2006 and have the Company's independent auditors provide an opinion on management's process for evaluating the internal controls and their effectiveness at December 31, 2006.

Business Risks

Luke Energy operates in a business environment that is subject to numerous risks, some of which are within the Company's ability to manage and some of which are beyond its control. By adhering to its effective business strategies, Luke can manage those risks within its control and partially mitigate the risks that are associated with the industry.

The prospect of finding oil and gas reserves in commercial quantities is inherently uncertain, and significant financial resources must be employed before production can be brought on-stream. To minimize this risk, Luke has employed a highly qualified exploration team to generate low to medium risk prospects in areas commensurate with the financial resources of the Company.

The Company focuses on exploring new areas to find oil and gas and to this end, extensive geological and geophysical analysis is performed prior to drilling. Once an area is targeted, the Company strives to build an extensive land base and maintain high working interests in its prospects.

Luke also mitigates its risk by employing a technically strong team of engineers to evaluate potential acquisitions which have development potential. The Company also strives to reduce outside risk by operating most of its production.

The Company strives to maintain a balance between the use of cash flow, equity markets and debt. While Luke currently has significant working capital and an unused credit line, it does not intend to allow its debt to exceed two times annual cash flow.

Once reserves are brought on-stream, there are risks associated with transportation and markets for oil and gas, especially for a junior oil and gas company. To reduce these risks, Luke endeavors to arrange firm transportation service where possible and closely monitor market pricing.

Commodity price volatility is also a significant risk to oil and gas producers. Prices for oil and gas are related to conditions beyond the Company's control such as worldwide supply and demand, competition, the US dollar exchange rate and weather related seasonal changes in demand. When production grows, Luke may, from time to time, utilize the combination of fixed price contracts and financial instruments to mitigate the risk of price volatility.

The industry is subject to extensive regulations imposed by governments related to the protection of the environment. Environmental legislation has undergone major revisions resulting in more stringent environmental and compliance standards in recent years. Luke is committed to operating in a manner that meets or exceeds the required standards and compliance guidelines. In addition, the Company strives to minimize the impact of its activities on the environment by using the best available technologies.

Management's Report

The accompanying financial statements of Luke Energy Ltd. and all other financial and operating information contained in this annual report are the responsibility of management. The financial statements have been prepared in accordance with accounting policies detailed in the notes to the financial statements and in accordance with Canadian generally accepted accounting principles. Financial statements are not precise as they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this annual report has been prepared on a basis consistent with that in the financial statements.

The systems of internal control have been designed and maintained to provide reasonable assurance that assets are properly safeguarded and that the financial records are sufficiently well maintained to provide relevant, timely and reliable information to management.

External auditors, appointed by the shareholders, have independently examined the financial statements. They have performed such tests as they deemed necessary to enable them to express an opinion on these financial statements.

An Audit & Reserves Committee of the Board of Directors, comprised of non-management Directors, has reviewed these financial statements with management and the external auditors. The Board of Directors has approved the financial statements on the recommendation of the Audit & Reserves Committee.

Harold V. Pedersen
President & CEO

Carrie L. McLauchlin
Vice-President, Finance & CFO

Auditors' Report to the Shareholders

We have audited the balance sheets of Luke Energy Ltd. as at December 31, 2004 and 2003 and the statement of earnings and retained earnings and cash flows for the year ended December 31, 2004 and the period from January 9, 2003 to December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the year ended December 31, 2004 and the period from January 9, 2003 to December 31, 2003 in accordance with Canadian generally accepted accounting principles.

Canadian generally accepted accounting principals vary in certain significant respects from accounting principles generally accepted in the United States of America. Information relating to the nature and effect of such differences is presented in note 13 of the financial statements.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 8, 2005

Balance Sheets

	December 31, 2004	December 31, 2003
Assets		(restated [1])
Current assets:		
Cash and cash equivalents	**$ 21,893,603**	$ 36,699,571
Accounts receivable	**2,697,334**	529,815
	24,590,937	37,229,386
Capital assets (note 4)	**34,856,766**	7,998,257
	$ 59,447,703	$ 45,227,643
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 7,382,282**	$ 2,203,148
Asset retirement obligations (note 6)	**509,330**	110,930
Future taxes (note 9)	**1,055,250**	98,850
Shareholders' equity:		
Share capital (note 7)	**48,130,532**	42,223,171
Contributed surplus	**900,033**	221,710
Retained earnings	**1,470,276**	369,834
	50,500,841	42,814,715
	$ 59,447,703	$ 45,227,643

1 See note 3 to the financial statements

See accompanying notes to financial statements.

On behalf of the Board:

Director
Harold V. Pedersen

Director
Mary C. Blue

Statements of Earnings and Retained Earnings

	Year Ended December 31, 2004	Period Ended December 31, 2003 (restated [1])
Revenue:		
Oil and gas production	$ 10,705,520	$ 1,715,620
Royalties, net of Alberta Royalty Tax Credit	(2,008,592)	(434,687)
	8,696,928	1,280,933
Other income:		
Interest	778,053	953,464
Gain (loss) on sale of marketable securities	(295,235)	629,575
	482,818	1,583,039
Expenses:		
Operating	1,991,048	262,754
General and administrative	1,962,188	1,126,790
Stock-based compensation	698,113	221,710
Interest	–	2,680
Depletion, depreciation and accretion	2,357,955	493,404
	7,009,304	2,107,338
Earnings before taxes	2,170,442	756,634
Taxes (note 9):		
Current	5,000	96,800
Future	1,065,000	290,000
	1,070,000	386,800
Earnings	$ 1,100,442	$ 369,834
Retained earnings, beginning of period	369,834	–
Retained earnings, end of period	1,470,276	369,834
Weighted average number of common shares outstanding (note 8)	35,204,971	29,759,428
Earnings per share – basic and diluted	$ 0.03	$ 0.01

1 See note 3 to the financial statements

See accompanying notes to financial statements.

Statements of Cash Flows

	Year Ended December 31, 2004	Period Ended December 31, 2003 (restated [1])
Cash provided by (used in):		
Operating:		
Earnings for the period	$ 1,100,442	$ 369,834
Items not affecting cash:		
Depletion, depreciation and accretion	2,357,955	493,404
Future taxes	1,065,000	290,000
Stock-based compensation	698,113	221,710
	5,221,510	1,374,948
Change in non-cash working capital (note 10)	(1,008,292)	45,959
	4,213,218	1,420,907
Financing:		
Common shares issued, net of issues costs (note 7)	5,735,721	38,486,155
Stock options exercised	43,250	–
Initial common shares redeemed for cash	–	(100)
	5,778,971	38,486,055
Investing:		
Additions to capital assets	(28,818,064)	(4,834,865)
Change in non-cash working capital (note 10)	4,019,907	1,627,374
	(24,798,157)	(3,207,491)
Increase (decrease) in cash	(14,805,968)	36,699,471
Cash and cash equivalent, beginning of period	36,699,571	100
Cash and cash equivalent, end of period	$ 21,893,603	$ 36,699,571

1 See note 3 to the financial statements

See accompanying notes to financial statements.

Notes to Financial Statements

Periods ended December 31, 2004 and 2003

1. INCORPORATION AND PLAN OF ARRANGEMENT:

Luke Energy Ltd. ("Luke Energy" or the "Company") is engaged in the acquisition, exploration, development and production of oil and gas reserves in western Canada.

The Company was incorporated pursuant to the Canada Business Corporations Act on January 9, 2003 as a wholly-owned subsidiary of KeyWest Energy Corporation ("KeyWest"). Pursuant to a plan of arrangement between Viking Energy Royalty Trust, Viking Holdings Inc., Viking KeyWest Inc., KeyWest and Luke Energy, KeyWest transferred interests in certain petroleum and natural gas properties and related facilities ("Retained Assets") to Luke Energy in exchange for common shares in Luke Energy. On February 26, 2003, the closing of the plan of arrangement, the common shares of Luke Energy held by KeyWest were distributed to the shareholders of KeyWest on a one for ten basis. Luke Energy began trading on the Toronto Stock Exchange on February 28, 2003.

The following summarizes the transfer of the Retained Assets which were initially recorded at KeyWest's net book value as Luke Energy and KeyWest were related parties. The amounts were then adjusted for the recording of asset retirement obligations and the future tax asset. The results of the operations of the Retained Assets were included from February 26, 2003.

Net assets acquired and liabilities assumed:

Petroleum and natural gas rights	$	2,482,106
Equipment and facilities		1,126,009
Future tax asset		628,550
Asset retirement obligation		(62,250)
	$	4,174,415
Consideration:		
Issuance of 6,581,364 common shares	$	4,174,415

2. SIGNIFICANT ACCOUNTING POLICIES:

The financial statements of the Company have been prepared in accordance with generally accepted accounting principles in Canada. In all material respects, these accounting principles are generally accepted in the United States except as described in note 13.

The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingencies at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results may differ from these estimates.

Cash and Cash Equivalents

Cash and cash equivalents includes highly liquid, short-term investments with a maturity of ninety days or less at the time of issue.

Capital Assets

The Company follows the full cost method of accounting for petroleum and natural gas operations, whereby all costs of exploring, developing and acquiring petroleum and natural gas properties, including asset retirement costs, are capitalized and accumulated in one cost centre. Costs include land acquisition costs, geological and geophysical charges, carrying charges on non-productive properties, costs of drilling both productive and non-productive wells, tangible production equipment and that portion of general and administrative expenses directly attributable to exploration and development activities. Gains and losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more.

Depletion and Depreciation

All costs of acquisition, exploration and development of oil and gas reserves, associated well equipment and facilities (net of salvage value), and estimated costs of future development of proven undeveloped reserves are depleted and depreciated by the unit-of-production method based on estimated proven reserves before royalties as determined by independent engineers. Natural gas reserves and production are converted to equivalent barrels of crude oil based on relative energy content of six Mcf of gas to one barrel of oil. Costs of unproved properties are initially excluded from depletion calculations. These unproved properties are assessed periodically to ascertain whether impairment has occurred. When proven reserves are assigned or the property is considered impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

Depreciation of office furniture and equipment is provided using the straight-line method based on estimated useful lives.

Ceiling Test

In applying the full cost method, the Company calculates a ceiling test whereby the carrying value of petroleum and natural gas properties is compared annually to the sum of the undiscounted cash flows expected to result from the Company's proved reserves and the lower of cost and market of unproved properties. Cash flows are based on third party quoted forward prices, adjusted for the Company's contracted prices and quality differentials. Should the ceiling test result in an excess of carrying value, the Company would then measure the amount of impairment by comparing the carrying amounts of petroleum and natural gas properties to an amount equal to the estimated net present value of future cash flows from proved plus

probable reserves and the lower of cost and market of unproved properties. The Company's risk-free interest rate is used to arrive at the net present value of the future cash flows. The excess of the carrying value over future cash flows would be recorded as a permanent impairment.

Asset Retirement Obligations

The Company recognizes the fair value of an asset retirement obligation in the period in which it is incurred when a reasonable estimate of fair value can be made. The fair value is based on estimates of future costs, reserve life, inflation and discount rates. The provision is recorded as a long-term liability, with a corresponding increase in the carrying value of the associated asset. The capitalized amount is depleted on a unit-of-production basis based on estimated proven reserves before royalties as determined by independent engineers. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the asset retirement obligation. Actual asset retirement expenditures are charged against the liability to the extent of the liability recorded.

Joint Interest Operations

A portion of the Company's exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Flow-through Shares

The resource expenditure deductions related to exploratory activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. A future tax liability is recognized and share capital is reduced by the estimated tax cost of the renounced expenditures when the renunciation is made.

Stock-based Compensation Plans

The Company has a stock-based compensation plan as described in note 7. The Company uses the fair value method of accounting for stock-based compensation whereby the Company recognizes the cost of stock options granted to employees, directors and certain consultants. The fair value of stock options is determined using the Black-Scholes option pricing model. Consideration paid by the option holder on exercise of stock options is recorded as share capital.

Income Taxes

The Company uses the liability method of tax allocation accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse.

Foreign Currency Translation

At year-end monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the year-end exchange rates. Gains or losses on translation are included in earnings.

Use of Estimates

The amounts recorded for depletion, depreciation and accretion of capital assets and the provision of future site restoration are based on estimates. The ceiling test is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

Per Share Amounts

Basic earnings per common share are computed by dividing earnings by the weighted average number of common shares outstanding for the period. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares, including stock options, were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments.

3. CHANGES IN ACCOUNTING POLICIES

Stock-based Compensation:

Pursuant to an amended accounting pronouncement for stock-based compensation, the Company changed its accounting policy on January 1, 2004 from the intrinsic method to the fair value method to account for options granted under the stock option plan. Application of the fair value method results in recognition of compensation expense in the statement of earnings with a corresponding amount recorded as contributed surplus. The new method was applied retroactively with restatement of the prior period financial statements. The change resulted in a reduction in earnings of $698,113 ($0.02 per share) for the year ended December 31, 2004 and $214,092 ($0.01 per share) for the period ended December 31, 2003.

Flow-through Shares

On March 16, 2004 the Emerging Issues Committee of the CICA clarified that estimated future tax costs of expenditures renounced to flow-through shareholders should be recorded when the expenditures are renounced. Prior to March 16, 2004 the Company recorded the estimated tax cost of the renounced expenditures on the date the shares were issued. As a result, the Company has not recorded an estimated tax cost for the flow-through shares issued in 2004. Accordingly, the cost will be recorded in 2005 when the renunciation is made.

4. CAPITAL ASSETS

	2004		2003	
	Cost	**Accumulated depletion and depreciation**	Cost	Accumulated depletion and depreciation
Petroleum and natural gas properties, including well equipment	**$ 37,299,505**	**$ 2,724,000**	$ 8,311,208	$ 463,000
Office furniture and Equipment	**390,750**	**109,489**	175,983	25,934
	$ 37,690,255	**$ 2,833,489**	$ 8,487,191	$ 488,934
Net book value		**$ 34,856,766**		$ 7,998,257

At December 31, 2004, costs of $6.7 million (2003 – $2.8 million) related to unproven properties have been excluded from the depletion calculation. In addition, $3.3 million of costs (including $2.2 million of pipe and casing inventory) incurred for the 2005 Marten Creek drilling program were excluded from the depletion calculation. In 2004, the Company capitalized $548,037 (2003 – $188,475) of general and administrative expenses directly related to exploration and development activities.

Included in the Company's petroleum and natural gas properties is $438,869 (2003 – $98,044), net of accumulated depletion, relating to the asset retirement obligation.

At December 31, 2004, flow-through share arrangements require the Company to incur approximately $5.5 million in exploratory costs prior to December 31, 2005.

The Company performed a ceiling test calculation at December 31, 2004 to assess the recoverable value of petroleum and natural gas properties. The present value of future net revenues from the Company's proved plus probable reserves exceeded the carrying value of the Company's petroleum and natural gas properties at December 31, 2004. The calculation was based on the year-end independent engineering evaluation (forecasted price case).

The future pricing assumptions used in the engineering evaluation are as follows:

Year	Oil WTI Ref ($US/bbl)	Foreign Exchange Rate	NaturalGas AECO Spot ($Cdn/MMbtu)
2005	42.00	0.82	6.60
2006	40.00	0.82	6.35
2007	38.00	0.82	6.15
2008	36.00	0.82	6.00
2009	34.00	0.82	6.00
2010-12	33.00	0.82	6.00
2013-15	+1.5%/yr.	0.82	+1.5%/yr.
2016+	+2.0%/yr.	0.82	+2.0%/yr.

5. CREDIT FACILITY

The Company has an $11 million production loan facility available with a major Canadian bank. Pursuant to the terms of the agreement, any amounts owing will revolve until September 30, 2005 and for a further period of 364 days thereafter at the request of the Company and with the consent of the bank. During the revolving phase, the loan has no specific terms of repayment. The facility bears interest at the lenders' prime lending rate or the Banker's Acceptance rate plus a margin based on the ratio of debt to cash flow, currently set as nil and 1.25% respectively. A standby fee of 0.2% per annum is levied on the unused portion of the facility.

Upon the expiration or termination of the revolving phase of the loan, any balance outstanding on the loan converts to a two-year term loan. The first repayment of one half of the outstanding balance is due on the 366th day after conversion followed by four quarterly repayments. During the term loan phase, interest rates will increase 0.5% from those during the revolving phase.

The facility is secured by a first floating charge demand debenture over all of the Company's assets.

Subsequent to year-end the Company arranged for an increase in the production loan facility to $16 million.

6. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by management based on the Company's net ownership in wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. At December 31, 2004 the net present value of the total asset retirement obligation is estimated to be $509,330 based on a total future liability of $809,000. These payments are expected to be made over the next 29 years with the majority of costs incurred between 2010 and 2023. The Company's credit adjusted risk free rate of eight percent and an inflation rate of 1.5 per cent were used to calculate the present value of the asset retirement obligation.

The following table reconciles the Company's asset retirement obligations:

		2004		2003
Carrying amount, beginning of the period	$	**110,930**	$	–
Recorded on acquisition of properties (note 1)		–		62,250
Increase in liabilities, during the period		**385,000**		44,210
Accretion expense		**13,400**		4,470
Carrying amount, end of period	$	**509,330**	$	110,930

7. SHARE CAPITAL

The Company is authorized to issue an unlimited number of common shares together with an unlimited number of preferred shares issuable in series.

Common Shares

Common shares issued and outstanding:

	Number of Shares		Amount
Balance at January 9, 2003, date of incorporation	100	$	100
Initial shares redeemed for cash	(100)		(100)
Issued on completion of the plan of arrangement (note 1)	6,581,364		4,174,415
Issued through private placement to directors, officers and employees	1,645,000		1,332,450
Conversion of special warrants	24,827,585		36,000,000
Issued through private placement of flow-through shares	1,775,000		3,550,000
Future tax effect on flow-through shares	–		(1,329,000)
Share issue costs	–		(2,396,294)
Future tax effect of the share issue costs	–		891,600
Balance at December 31, 2003	34,828,949	$	42,223,171
Issued through private placement of flow through shares	2,127,207		6,000,002
Share issue costs	–		(264,281)
Future tax effect of share issue costs	–		108,600
Exercise of stock options	41,667		63,040
Balance at December 31, 2004	36,997,823	$	48,130,532

In December 2004, the Company issued 806,452 common shares on a tax flow-through basis at $3.10 per share for proceeds of $2.5 million. Management and directors subscribed for approximately 13% of the issue. In September 2004, the Company issued 1,320,755 common shares on a tax flow-through basis at $2.65 per share for proceeds of $3.5 million. Management and directors subscribed for 25% of the issue.

Under the terms of these private placements the Company is committed to expend the proceeds on qualifying exploration drilling and seismic prior to December 31, 2005 and renounce the tax benefits to the subscribers by December 31, 2004.

In September 2003, the Company issued 1,775,000 common shares on a tax flow-through basis at $2.00 per share for proceeds of $3.6 million. Management and directors subscribed for 50% of the issue. Under the terms of the private placement the proceeds were expended on qualifying exploration drilling and seismic prior to December 31, 2004.

In March, 2003 the Company completed a private placement of 24,827,585 special warrants for gross proceeds of $36,000,000. The proceeds of this financing were placed in escrow until shareholder approval was received on April 14, 2003. At that time the special warrants were deemed to be exercised for common shares on a one for-one basis without additional consideration. Management and directors subscribed for approximately 10% of the issue.

Stock-based Compensation Plan

Pursuant to Luke Energy's Stock Option Plan, ("the Plan"), the Company was entitled to reserve for issuance and grant stock options to a maximum of 3.3 million shares on a cumulative basis (not to exceed 10% of the issued and outstanding shares of Luke Energy on an undiluted basis). Options granted under the Plan to date have a term of five years to expiry. Options vest equally over a three-year period starting on the first anniversary date of the grant. The exercise price of each option equals the market price of the Company's common shares on the date of the grant.

A summary of the status of the Plan at December 31, 2004 and 2003, and changes during the periods ended is presented below:

	2004		2003	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Stock options, beginning of period	**2,665,000**	**$1.52**	–	–
Granted	**591,000**	**$2.38**	3,055,000	$1.51
Exercised	**(41,667)**	**(1.04)**	–	–
Cancelled	**–**	**–**	(390,000)	$1.39
Stock options, end of period	**3,214,333**	**$1.69**	2,665,000	$1.52
Exercisable, end of period	**846,667**	**$1.55**	–	–

The following table summarizes information about the stock options outstanding at December 31, 2004:

	Options Outstanding at December 31, 2004		
Range of Exercise prices	Number of Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
Less than $1.00	643,333	3.14	$0.81
$1.00 to $2.00	1,980,000	3.69	$1.77
Greater than $2.00	591,000	4.67	$2.38
	3,214,333	3.76	$1.69

The fair value of each stock option was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions: risk-free interest rate of 5%, dividend yield of 0%, expected life of 5 years, and volatility of 45%. The fair value of options issued in the year was calculated at $652,071.

8. PER SHARE AMOUNTS

In computing diluted earnings per share, 124,639 shares were added to the weighted average number of common shares outstanding during the year ended December 31, 2004 for the dilutive effect of all employee stock options and warrants (2003 – 581,480). No adjustments were required to reported earnings from operations in computing diluted per share amounts.

9. TAXES

The future income tax liability includes the following temporary differences:

	2004	2003
Capital assets	$ 1,961,738	$ 928,432
Share issue costs	(582,867)	(667,817)
Asset retirement obligations	(171,237)	(35,139)
Attributable crown royalty income	(96,850)	–
Non-capital losses	(55,534)	(126,626)
	$ 1,055,250	$ 98,850

The provision for income taxes differs from the amount computed by applying the combined federal and provincial tax rates to earnings before income taxes. The difference results from the following:

	2004	2003
Earnings before taxes	$ 2,170,442	$ 756,634
Combined federal and provincial tax rate	38.87%	40.62%
Computed "expected" tax	$ 843,651	$ 307,345
Increase (decrease) in taxes resulting from:		
Non-deductible crown charges, net of ARTC	444,047	29,066
Non-taxable portion of capital gain (loss)	57,379	(127,866)
Non-deductible stock-based compensation expense	271,357	90,059
Other non-deductible expenses	13,830	9,877
Effect of change in corporate tax rate	(90,988)	(50,558)
Resource allowance	(377,426)	32,077
Attributable crown royalty income	(96,850)	–
Large corporations tax	5,000	96,800
Reported income taxes	$ 1,070,000	$ 386,800

10. CASH FLOW INFORMATION

Change in non-cash working capital is summarized below:

	2004	2003
Accounts receivable	$ (2,167,519)	$ (529,815)
Accounts payable and accrued liabilities	5,179,134	2,203,148
	$ 3,011,615	$ 1,673,333
Non-cash working capital – operating	$ (1,008,292)	$ 45,959
Non-cash working capital – investing	4,019,907	1,627,374
	$ 3,011,615	$ 1,673,333

Amounts actually paid during the period relating to interest expense and capital taxes are as follows:

		2004		2003
Interest paid	$	–	$	2,680
Capital taxes paid	$	101,800	$	–

11. FINANCIAL INSTRUMENTS

The financial instruments included in the balance sheets are comprised of accounts receivable and accounts payable and accrued liabilities. The fair values of these financial instruments approximate their carrying amounts due to the short-term maturity of the instruments.

All of the Company's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risk. Purchasers of the Company's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize risk of non-payment.

12. COMMITMENTS

At December 31, 2004 the Company had commitments for the lease of office space of approximately $220,000 a year until October 1, 2009.

13. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

These financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conforms to accounting principles generally accepted in the United States ("US GAAP"). The significant differences in those principles, as they apply to the Company's financial statements, are described below.

a) Full Cost Accounting

The Company is subject to a SEC prescribed ceiling test. In determining the limitation on capitalized costs, SEC rules require a 10 percent discounting of after-tax future net revenues from production of proved oil and gas reserves. To date, application of the SEC prescribed test has not resulted in a write-down of capitalized costs.

b) Flow-through Shares

The Company finances a portion of its activities with flow-through share issues whereby the tax deductions on expenditures are renounced to the share subscribers. Under Canadian GAAP the estimated cost of the tax deductions renounced to shareholders is reflected as a reduction of the stated value of the shares. The SEC

requires that when the qualifying expenditures are renounced to the shareholders, the estimated tax cost of the renunciation, less any proceeds received in excess of the quoted value of the shares, is reflected as a tax expense.

c) Stock-based Compensation

Prior to 2004 the Company used the intrinsic method of accounting for stock options for both Canadian and US GAAP purposes. On January 1, 2004 the Company retroactively changed its method of accounting for stock options to the fair value method. While US GAAP continues to allow the use of either the intrinsic method, as prescribed by APB 25, or the fair value method, as prescribed by SFAS 123, the Company has elected to adopt the fair value method of accounting for stock options for US GAAP purposes. The new method has been applied retroactively with a restatement of prior US GAAP. This change resulted in a reduction in the US GAAP earnings of $698,113 ($0.02 per share) for the year ended December 31, 2004 and $214,092 ($0.01 per share) for the period ended December 31, 2003.

The following tables provide a reconciliation of earnings (loss) and the balance sheet impact for the differences between Canadian GAAP and US GAAP:

	Note	Year Ended December 31, 2004	Period Ended December 31, 2003
Earnings, as reported		$ 1,100,442	$ 369,834
Accounting for income taxes	(b)	–	(1,329,000)
Earnings (loss) – US GAAP		$ 1,100,442	$ (959,166)
Earnings (loss) per share – US GAAP		$ 0.01	$ (0.03)

As at December 31, 2004	Note	As Reported	Increase (Decrease)	US GAAP
Shareholders' equity				
Share capital	(b)	$ 48,130,532	$ 1,329,000	$ 49,459,532
Retained earnings	(b)	$ 1,470,276	$ (1,329,000)	$ 141,276

As at December 31, 2003	Note	As Reported	Increase (Decrease)	US GAAP
Shareholders' equity				
Share capital	(b)	$ 42,223,171	$ 1,329,000	$ 43,552,171
Retained earnings	(b)	$ 369,834	$ (1,329,000)	$ (959,166)

Depletion and Depreciation

Depletion per gross equivalent barrel is calculated by converting natural gas volumes to a barrel of oil equivalent using the ratio of 6 Mcf of natural gas to 1 barrel of oil. Depletion and depreciation as calculated in accordance with US GAAP for the year ended December 31, 2004 is $8.43 per boe (period ended December 31, 2003 – $10.41 per boe).

SAB 106

In September 2004 the SEC issued SAB 106 regarding the application of FAS 143 by oil and gas entities that follow the full cost accounting method. SAB 106 states that after the adoption of FAS 143 the future cash flows associated with the settlement of asset retirement obligations accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling test calculation. As the Company excludes these future cash outflows from its present value of estimated future net cash flows and does not reduce the capitalized oil and gas costs by the asset retirement obligation reflected on the balance sheet, the adoption of SAB 106 in 2004 did not have any impact on the Company's financial statements, nor did it have an effect on the results of the ceiling test calculation.

Accounting for Variable Interest Entities

In January 2003 the FASB issued Financial Interpretation 46, Accounting for Variable Interest Entities that requires the consolidation of Variable Interest Entities. As the Company does not have any financial interests in other entities, it does not believe FIN 46R results in the consolidation of any additional entities at December 31, 2004.

Accounting of Exchange of Nonmonetary Assets

In December 2004 the FASB issued FAS 153 which deals with the accounting for the exchanges of nonmonetary assets. FAS 153 is an amendment of APB Opinion 29. APB Opinion 29 requires that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. FAS 153 amends APB Opinion 29 to eliminate the exception from using fair market value for nonmonetary exchanges of similar productive assets and introduces a broader exception for exchanges of nonmonetary assets that do not have commercial substance. FAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not believe that the application of FAS 153 will have an impact on the financial statements.

Corporate Information

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Vice-Chairman
Calgary, Alberta

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Montreal, Quebec

Alain Lambert [2]
Montreal, Quebec

Hugh Mogensen [1]
Chairman
Victoria, B.C.

Harold V. Pedersen [2]
President & CEO
Calgary, Alberta

Lyle D. Schultz [3]
Calgary, Alberta

J. Ronald Woods [1,3]
Toronto, Ontario

1 Audit & Reserves Committee
2 Compensation Committee
3 Corporate Governance Committee

Management

Harold V. Pedersen
President & CEO

Robert E. Wollmann
Vice-President, Exploration

Kevin Lee
Vice-President, Engineering

Carrie McLauchlin
Vice-President, Finance & CFO

Peter W. Abercrombie
Vice-President, Land

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